

Statement of Basis

July 27, 2012

*Sklar Exploration, LLC—
Castleberry Oil & Gas Field, Area No. 3 Oil & Gas Production Wells*

Facility No. 502-0090

Off of Conecuh Co. 6
Near Brooklyn, Conecuh Co., AL

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Authority

The initial Title V Major Source Operating Permit is issued under the provisions of ADEM Admin. Code R. 335-3-16. The above named applicant has requested authorization to perform the work or operate the facility shown on the application and drawings, plans, and other documents attached hereto or on file with the Air Division of Alabama Department of Environmental Management, in accordance with the terms and conditions of this permit.

This initial Major Source Operating Permit will cover fifty-six (56) onshore oil and gas production wells. These wells are mostly located along Conecuh Co. 6 between Brooklyn and Johnstonville, AL.

Critical Dates

This Area has been operating under Air Permits since November 20, 2008. On April 22, 2011, the facility was permitted for enough wells to make it a major source of criteria pollutants. Per ADEM Rule 335-3-16-.04(2), a facility operating under an Air Permit that is a Major Source with respect to Title V is required to submit a permit application within 12 months of commencing operation. A permit application was due by April 22, 2012. The Permittee submitted the initial permit application on April 19, 2012. The application was revised on June 12, 2012.

Statement of Basis & Permit Architecture

The Statement of Basis will re-visit regulatory applicability, primarily NSPS OOOO which was recently promulgated. Even though the Statement of Basis discusses a number of different units, the requirements for these units will be included under the Emergency Flares section. The primary reason for this is that each flare acts as a control device for all other units located at an individual wellsite. The secondary reason is that the facility-wide limit to be a synthetic minor source with respect to Prevention of Significant Deterioration [PSD] is based on limits pertaining to the flare, including which burns gas volumes from other parts of the wellsite, in addition to excess produced gas.

On April 17, 2012, EPA finalized New Source Performance Standard Subpart OOOO [NSPS OOOO]. This regulation applies to equipment at wells constructed after August 23, 2011. The following table summarizes the wells to be covered by this permit constructed prior to August 23, 2011, and after August 23, 2011:

Emission Point	Production Site Name	Emission Point	Production Site Name
Sections [5, 6, 7, & 8], Township 3 North, Range 13 East			
0507A	Logan 5-7	0704A	CCL&T 7-4
Sections [19, 20, 29, 30, 31, 32, & 33], Township 4 North, Range 13 East			
2910A	Thomasson 29-10	3102A	Mary Mack 31-2
3203A	Hamiter 32-3		
Sections [33, 34, 35, & 36], Township 4 North, Range 12 East			
3508A	CCL&T 35-8	3510A	CCL&T 35-10

Table 1: Pre-August 23, 2011, Sites

Emission Point	Production Site Name	Emission Point	Production Site Name
Sections [5, 6, 7, & 8], Township 3 North, Range 13 East			
05NWA	5-NW [Generic]	06NWA	6-NW [Generic]
05SEA	5-SE [Generic]	06SEA	6-SE [Generic]
05SWA	5-SW [Generic]	06SWA	6-SW [Generic]
07NEA	7-NE [Generic]	08NEA	8-NE [Generic]
07SEA	7-SE [Generic]	08NWA	8-NW [Generic]
07SWA	7-SW [Generic]	08SEA	8-SE [Generic]
06NEA	6-NE [Generic]	08SWA	8-SW [Generic]
Sections [19, 20, 29, 30, 31, 32, & 33], Township 4 North, Range 13 East			
19NEA	19-NE [Generic]	20NWA	20-NW [Generic]
19NWA	19-NW [Generic]	20SEA	20-SE [Generic]
19SEA	19-SE [Generic]	20SWA	20-SW [Generic]
19SWA	19-SW [Generic]	31NWA	31-NW [Generic]
29NEA	29-NE [Generic]	31SEA	31-SE [Generic]
2906A	Boothe-Casey 29-6	31SWA	31-SW [Generic]
29SWA	29-SW [Generic]	13-33NEA	13-33-NE [Generic]
3008A	Ralls 30-8	13-33NWA	13-33-NW [Generic]
32SEA	32-SE [Generic]	13-33SEA	13-33-SE [Generic]
32NEA	32-NE [Generic]	13-33SWA	13-33-SW [Generic]
20NEA	20-NE [Generic]		
Sections [33, 34, 35, & 36], Township 4 North, Range 12 East			
123302A	CCL&T 12-33-2	3408A	Graddy 34-8
123306A	CCL&T 12-33-6	3410A	Graddy 34-10
123310A	CCL&T 12-33-10	3414A	CCL&T 34-14
123312A	CCL&T 12-33-12	36NEA	36-NE [Generic]
3505A	CCL&T 35-5	36NWA	36-NW [Generic]
3511A	CCL&T 35-11	36SEA	36-SE [Generic]
3404A	Jones 34-4	36SWA	36-SW [Generic]

Table 2: Post-August 23, 2011, Sites

Facility-wide Potential Emissions

The following table summarizes the potential facility-wide emissions

Facility-Wide Potential Emissions								
Castleberry Area No. 3 Oil & Gas Production Wells								
Emissions Sources	(Tons/yr)						(Metric Tons/yr)	
	PM	SO ₂	NO _x	CO	VOC	HAPs	CO ₂ e	GHG Mass
(56) Heater Treaters	1.83	0.32	24.05	20.20	1.32	Negligible	26030.51	26005.55
(56) Emergency Flares	-	0.72	38.00	206.77	213.70	Negligible	67216.61	63731.07
Total Emissions:	1.83	1.04	62.05	226.97	215.02	Negligible	93247.13	89736.62

Table 3: Potential Facility-wide Emissions [Ton/yr]

Facility History

The Castleberry Oil and Gas Field, Area No. 3, is part of the Little Cedar Creek Field, as named by the State of Alabama Oil & Gas Board. The wells included in the Little Cedar Creek Field have been permitted primarily to Sklar Exploration, hereafter Sklar, and Pruet Production Company, hereafter Pruet. The 30-1 well, now permitted to Pruet, was the initial well in this area, was permitted for well testing on November 14, 1994, to Hunt Oil Company. Since then, additional wells have been discovered, drilled, permitted, and constructed.

Additionally, the geographic locations of the various wells have led the Little Cedar Creek Field to be divided as it has been developed. Sklar began with Area No. 1 [Facility No., 103-0021], and now has Area No. 2 [Facility No. 103-0026], and Area No. 3 [Facility No. 502-0090], for which this permit is proposed. It should be noted that this Area has an Escambia County number since the initial well was the Logan 5-7 near the Escambia County line. However, the field developed northward across the border such that now the bulk of the wells in this Area are actually in Conecuh County.

Table 4 summarizes the permit history of this facility:

Issuance Date	Permittee	Permit Type	Permit No.	Unit(s) Permitted	Total No. Permitted Wells
11/14/2011	Sklar Exploration	Air	X004	Permit for (56) Wellsites	56
6/1/2011	Sklar Exploration	Air	X004	Permit for (16) Additional Wellsites	56
4/22/2011	Sklar Exploration	Air	X003	Permit for (20) Additional Wellsites	40
1/22/2009	Sklar Exploration	Air	X002	Permit for (20) Wellsites	20
11/20/2008	Sklar Exploration	Air	X001	Permit for (16) Wellsites	16

Table 4: Facility Permit History

Permit Grouping Methodology

EPA currently has no official guidance pertaining to the permitting of oil and gas production sites, either as groups, or individually. The last document that addressed this topic was released in January 2007, and is known as the Wehrum Memorandum. This document, since rescinded, advised that onshore production sites should be permitted separately.

The first production sites permitted by the Department were located far enough from other sites under common ownership/operatorship that they were permitted separately. However, beginning in 2005, owners/operators began submitting permit applications for multiple oil and gas wells, with some of them in fairly close proximity to each other.

In order to follow the "Sensible Grouping" rule applied to compressor stations, the Department began permitting all wells under common ownership/operatorship in four square-mile sections, called "Areas", together. Additionally, as a bookkeeping method, these Area boundaries generally followed township section lines. In permitting these Areas, the Department examined the aggregate emissions of all wells within the Area boundaries for the purposes of determining the applicability of Prevention of Significant Deterioration [PSD] and Title V regulations. This is clearly more stringent than EPA's advice in the now-rescinded guidance document mentioned above.

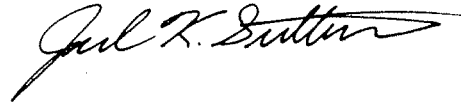
Over time, the "Sensible Grouping" rule has evolved into permitting proposed wells as follows, for both PSD and Title V purposes:

1. Checking the distance from the proposed well to the nearest well under common ownership/operatorship.
2. Aggregating the expected emissions from the proposed well with:
 - a. Those from each well that is located one mile, or less, from the proposed location under common ownership/operatorship.
 - b. All wells currently permitted under the same Area grouping that includes the wells that are one mile, or less, from the proposed well.
3. Where possible, continuing to utilize township sections as the primary building blocks of each Area, although there is now no limit on the Area size.

One of the challenges of permitting these sites is that the drilling schedule is a variable. Thus, it is difficult for the Permittee to predict where the next drilling site will be, and in what order these sites will be drilled. In order to streamline the permitting process, the Department has allowed owners/operators to apply for a finite number of wells, even if all of the exact sites are unknown. This allows the owner/operator some flexibility in the development of the field, while still ensuring that permits are issued. Emissions from these "Generic Wells" are counted towards the total Area potential emissions. This method works since each site has approximately the same equipment [(1) 0.5 MMBTU/hr heater treater, (1) flare stack, (2) condensate storage tanks, (1) salt water storage tank, and (1) power oil storage tank]. As part of the Temporary Authorization to Operate request, the owner/operator is required to submit the name of the wellsite, along with the UTM coordinates.

Recommendations

This Statement of Basis indicates that these sources should meet the requirements of all federal and state rules and regulations, as described on the following pages. Therefore, I recommend that Sklar be issued the initial Major Source Operating Permit No. 502-0090 for these sources.



Joel K. Sutton
Industrial Minerals Section
Energy Branch
Air Division

July 27, 2012

Date

Process Description

There are two related processes for each well which will be covered by Major Source Operating Permit No. 502-0090.

Process No. 1—Oil & Gas Extraction:

Oil and associated sour gas flows from a well into a low pressure separator. In the process, the primary separation of gas and liquids from the well occurs in the separator. After the separator, the gas goes to the sour gas flare or to the nearby Plains Gas Solutions North Beach Gas Treating Facility (Facility No. 103-0029). The liquids leave the separator and pass through a heater treater which primarily separates oil and water which flow into the storage tanks until sale or custody transfer. A Vapor Recovery Unit (VRU) is used to capture stock tank vapors and send the vapors to the gas plant (Facility 103-0029) or the onsite well flares. An electric power oil pump motor is used to pump oil from one of the tanks back into the ground in order to facilitate the extraction process.

Process No. 2—Oil Extraction:

In the event that the gas plant is offline or the well is not connected to the gas plant via a pipeline, these wells may be used to produce oil. This process is similar to the oil and gas extraction process except that the gas is continuously flared.

The following pages outline the regulations which apply to the various pieces of equipment at each wellsite. Each well is equipped with one (1) heater treater, one (1) emergency flare, one (1) salt water storage tank, and two (2) crude oil storage tanks. Each well is also permitted for one (1) power oil storage tank.

No site is equipped with an internal combustion engine.

Hydraulically Fractured Sites & Gas Production Sites

There are various stages of gas well completion [re-completion for wells that have slowed or ceased production]. One of the last steps involves puncturing, or perforating, the underground rock formation to release the natural gas and associated petroleum liquids. There are a number of methods used to accomplish this, including the insertion of acid into the ground. Of particular concern is hydraulic fracturing [hydro-fracking or fracking], which involves injecting a liquid chemical solution at a very high pressure into the underground formation.

This facility is comprised of 56 oil and gas production sites, comprising the well and other surface equipment, in various stages of completion. All of the completed wells have been designated as Oil Wells by the State of Alabama Oil & Gas Board. However, these wells do produce gas.

Regulatory Applicability:

This section will summarize the regulatory applicability for these units.

Prevention of Significant Deterioration [PSD]

This facility is a 250-Ton source for the purposes of PSD. Even though the facility as a whole has a limit to be a synthetic minor source with respect to PSD, there are no limits set by this regulation for hydraulically fractured wells.

40 CFR 60 Subpart OOOO [NSPS OOOO]

This rule was promulgated by EPA on April 17, 2012. This regulation applies to both hydraulically fractured wells [§60.5365(h) & §60.5340] and other gas wells [§60.5365(a) & §60.5430] that were completed or re-completed after August 23, 2011. Tables 1 and 2 show which wells were constructed before, and after, this date. This area currently has no hydraulically fractured wells. Additionally, well re-completions that follow the procedures specified in NSPS OOOO are not considered modified sources.

Title V

Each well would be subject to the requirements of this regulation.

Applicable Requirements

Each affected well completion should meet the following requirements:

1. During each hydraulic fracturing event occurring after §60.5375 August 23, 2011, the Permittee is to capture all liquids and vapors produced during the operation, maintain a daily completion log, and submit reports required by §60.5420.

Expected Emissions

The expected emissions from each completion operation should be minimal since most of the potential pollutants will be captured. The expected emissions for the Flares includes any emissions from the well completion phase.

Monitoring Approach

Periodic Monitoring

This section outlines the applicable periodic monitoring:

Periodic Monitoring will consist of sending reports and notifications required by NSPS OOOO to EPA for hydraulically fractured [and/or re-fractured] wells, and maintaining a daily completion log. One of the reports required by EPA is an initial completion notification. This report will be satisfied by the Temporary Authorization to Operate Request required by the Department prior to the well commencing production.

Compliance Assurance Monitoring [CAM]

For a unit to be subject to Compliance Assurance Monitoring (CAM), that unit must have a permit limit, a control device, and the potential to emit (PTE), pre-control, greater than 100 Ton/yr of any criteria pollutant or 10 Ton/yr of one Hazardous Air Pollutant (HAP) or 25 Ton/yr of all HAPs. Since none of the wellheads is a major source on its own, CAM is not applicable.

Heater Treaters

There are fifty-six (56) existing and proposed heater treaters located throughout this Area. Each heater treater is to be rated at 0.5 MMBTU/hr, and burn only natural gas, with propane as a secondary fuel. Each heater treater helps with the initial separation of the gas, liquid, and water components of the produced well stream.

Regulatory Applicability:

This section will summarize the regulatory applicability for these units.

Prevention of Significant Deterioration [PSD]

This facility is a 250-Ton source for the purposes of PSD. Even though the facility as a whole has a limit to be a synthetic minor source with respect to PSD, none of these heaters has a limit assigned by this regulation.

ADEM Administrative Code Rule 335-3-4-.03

This regulation requires all indirect heating units located in Conecuh County to meet a limit of 0.5 lb Particulate Matter/MMBTU Heat Input, or 0.25 lb Particulate/hr/heater. However, the combustion of natural gas would result in minimal Particulate Matter emissions.

ADEM Administrative Code Rule 335-3-5-.01(1)

This regulation requires all indirect heating units located in Conecuh County to meet a limit of 4.0 lb SO₂/MMBTU Heat Input, or 2.0 lb SO₂/hr/heater. Fuel for this unit would be pipeline-quality natural gas, which would result in minimal SO₂ emissions.

40 CFR 60 Subpart D_C [NSPS D_C]

Per §60.40c(a), this regulation applies to steam generating units rated between 10 MMBTU/hr and 100 MMBTU/hr. Since these units are classified as process heaters, and are rated below 10 MMBTU/hr, this regulation does not apply.

40 CFR 63 Subpart DDDDD [MACT DDDDD]

This regulation was promulgated on March 21, 2011, and applies to facilities that are major sources of Hazardous Air Pollutants [HAPs]. Since this facility is not a major source of HAPs, this regulation does not apply.

40 CFR 63 Subpart JJJJJ [MACT JJJJJ]

This regulation was promulgated on March 21, 2011. Per 40 CFR 63.11194, this regulation only applies to boilers located at Area Sources of HAPs. Since each of these units is classified as a process heater, this regulation does not apply.

Title V

These units are subject to this regulation. However, according to the Trivial and Insignificant Activities list (Section 2, Part A), any fuel burning equipment with a rating between 0.5 MMBTU/hr and 5 MMBTU/hr is considered trivial and insignificant, provided it is not subject to an NSPS or a MACT regulation, and is located at a Title V facility. All of these heating units fall within this rating range, and no MACT regulations or NSPS regulations apply to any of these heating units. Therefore, all of these heaters may be considered Trivial and Insignificant.

Applicable Requirements

Even though these units must comply with the state sulfur and particulate limits, they are classified as Trivial and Insignificant Activities.

Expected Emissions

The expected emissions were taken from the 2011 Title V emissions estimates for this portion of the field, and represent the emissions for the seven (7) operating sites at that time.

Expected emissions:

CO (Ton/yr)	0.51
VOC (Ton/yr)	~0
NO _x (Ton/yr)	0.47
SO ₂ (Ton/yr)	~0

Table 5: Expected Emissions from Heater Treaters

Monitoring Approach

Periodic Monitoring

No periodic monitoring is required since proper natural gas combustion results in negligible emissions and nearly zero percent opacity.

Compliance Assurance Monitoring [CAM]

For a unit to be subject to Compliance Assurance Monitoring (CAM), that unit must have a permit limit, a control device, and the potential to emit (PTE), pre-control, greater than 100 Ton/yr of any criteria pollutant or 10 Ton/yr of one Hazardous Air Pollutant (HAP) or 25 Ton/yr of all HAPs.

This regulation is not applicable since none of these units has a permit limit, the potential to emit greater than 100 Ton/yr, or a control device.

Equipment in VOC Service

Each wellsite has equipment in Volatile Organic Compound (VOC) service. This includes pumps, compressors, piping and pipe fittings, and pneumatic controllers. Pumps may be used to direct petroleum products from one location to another, including injection into the ground. Pneumatic controllers are run on a pressurized gas, some of which may escape as the valve operated by the controller opens and closes. Compressors are used for water injection, oil injection, or gas injection, in order to increase the underground reservoir pressure, resulting in better production. Piping and pipe fittings [valves, flanges, etc] are located throughout each wellsite.

This facility is comprised of 56 oil and gas production sites in various stages of completion. Each of the completed wells is planned to have a power oil pump driven by an electric motor.

Regulatory Applicability:

This section will summarize the regulatory applicability for these units.

Prevention of Significant Deterioration [PSD]

This facility is a 250-Ton source for the purposes of PSD. Even though the facility as a whole has a limit to be a synthetic minor source with respect to PSD, none of the controllers, pumps, or compressors has a limit assigned by this regulation.

40 CFR 60 Subpart OOOO [NSPS OOOO]

This rule was promulgated by EPA on April 17, 2012. This regulation applies to pumps, pneumatic controllers, and compressors [both reciprocating and centrifugal] constructed after August 23, 2011.

Centrifugal & Reciprocating Compressors: Per §60.5365(b) and (c), this regulation only applies to compressors located between the wellhead and the point of custody transfer, defined as follows, from §60.5430:

1. Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
2. Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.
3. Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Each well is planned to have a screw-type centrifugal compressor as part of the Vapor Recovery Unit [VRU] used to capture the stock tank vapors and route them to the flare, fuel gas, or the plant pipeline. This area currently has no reciprocating compressors. Additionally, the screw-type VRU compressors do not meet the definition of a centrifugal compressor, as defined above. Therefore, this portion of the regulation does not apply.

Pneumatic Controllers: Per §60.5365(d), this regulation applies to all natural gas-driven pneumatic controllers with a continuous natural gas bleed rate of 6 Scf/hr, or greater, located between a wellhead and custody transfer. The following definitions from §60.5430 must be considered:

1. Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.
2. Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.
3. Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.
4. Intermittent/snap-action pneumatic controller means a pneumatic controller that vents non-continuously.
5. Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.
6. Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

The pneumatic controllers in use at the wellsites only open as needed. Thus, they do not have a continuous bleed rate, and may be classified as *Intermittent/Snap Action pneumatic controllers*. Therefore, they do not meet the definition of a *Continuous bleed Natural gas-driven pneumatic controller*, and there are no applicable requirements.

Pumps, Piping, & Pipe Fittings: Per §60.5365(f)(2), only pumps and other ancillary equipment in VOC service located at a natural gas processing plant site is subject to the regulation. Since this facility does not meet the definition of a natural gas processing plant, any pumps at these sites would not be subject to this portion of the regulation.

40 CFR 63 Subpart HH [MACT HH]

This regulation applies to oil and gas production facilities that produce, upgrade, or store petroleum liquids and/or natural gas prior to custody transfer. This regulation contains both Major Source and Area Source requirements.

Major Source Requirements: The Major Source requirements of this regulation apply to equipment in HAPs service, including piping, and glycol dehydrators.

Per the definitions in §63.761, the Major Source determination is based on glycol dehydration unit HAPs emissions and Storage Tanks emissions from each wellsite, independent of any other wellsites in the vicinity. No wellsite is equipped with a glycol dehydrator. Additionally, the Storage Tanks should have negligible emissions since each tank is to be equipped with a closed vent system, as discussed later. Therefore, this area may be classified as an Area Source, and the Major Source requirements do not apply.

Area Source Requirements: The Area Source requirements of this regulation apply only to sites equipped with a Tri-ethylene Glycol [TEG] dehydration unit. Since no site is equipped with a glycol dehydrator of any kind, the Area Source requirements do not apply.

Title V

There are no requirements under this regulation since there are no affected sources.

Applicable Requirements

There are no applicable requirements for any of the equipment listed above since there are no affected sources.

Expected Emissions

The expected emission from these sources would be fugitive VOC emissions, which would be very low.

Monitoring Approach

Periodic Monitoring

Since there are no affected units subject to any emissions standards, no periodic monitoring is required.

Compliance Assurance Monitoring [CAM]

For a unit to be subject to Compliance Assurance Monitoring (CAM), that unit must have a permit limit, a control device, and the potential to emit (PTE), pre-control, greater than 100 Ton/yr of any criteria pollutant or 10 Ton/yr of one Hazardous Air Pollutant (HAP) or 25 Ton/yr of all HAPs.

This regulation is not applicable since none of these units has the potential to emit greater than 100 Ton/yr.

Wellsite Storage Vessels

Each wellsite is equipped with the storage tank battery comprised of the tanks shown in Table 6 below. This means that there is a maximum of 224 storage tanks that could be located throughout the area. It should be noted that the capacity of 10,567 gallons comes from the Trivial & Insignificant Activity List.

Tank Type	Capacity (gal.)	No. Tanks
Crude Oil Storage	20,000	2
Power Oil Pump	20,000	1
Produced Water Storage	20,000	1

Table 6: Storage Tank Summary/Wellsite

Regulatory Applicability

This section will summarize the regulatory applicability for these units.

Prevention of Significant Deterioration [PSD]

This facility is a 250-Ton source for the purposes of PSD since it is not one of the 28 source categories. Sklar has requested a facility-wide emissions limit of 245 Ton/yr for all criteria pollutants. Since any vapors released in the tanks would be captured and sent either to the wellsite flare or to the pipeline, these emissions have already been accounted for. Therefore, monitoring for the flare will be sufficient.

ADEM Administrative Code Rule 335-3-6-.03

This regulation applies to the loading and storage of volatile organic compounds. Per Rule 335-3-6-.03(4), this regulation does not apply to crude petroleum produced, separated, treated, or stored in the field. Since these tanks each store crude petroleum at the production source in the field, this regulation does not apply.

ADEM Administrative Code Rule 335-3-6-.04

This regulation applies to fixed roof petroleum liquid storage tanks. Per Rule 335-3-6-.03(3)(b), this regulation does not apply to storage tanks with a capacity less than 423,000 gallons, and used to store crude petroleum oil prior to custody transfer. Since these tanks each store crude oil prior to custody transfer, this regulation does not apply.

40 CFR 60 Subpart K_b [NSPS K_b]

This regulation applies to VOC tanks constructed after July 12, 1984. Per §60.110b(d)(4), vessels with a design storage capacity of less than, or equal to, 1590 m³ (420,000 gallons) used for petroleum or condensate stored, treated, or processed prior to custody transfer are exempt from this regulation. Each of the tanks at these sites has a volume of less than 420,000 gallons, and stores condensate prior to custody transfer. Therefore, these tanks are exempt from this regulation.

40 CFR 60 Subpart OOOO [NSPS OOOO]

This rule was promulgated by EPA on April 17, 2012. This regulation applies storage vessels constructed after August 23, 2011 [§60.5356(e)]. Therefore, all storage vessels at sites shown in Table 2 above are subject to this regulation. Storage vessels at sites shown in Table 1 would only be subject if they are reconstructed or modified.

40 CFR 63 Subpart HH [MACT HH]

This regulation applies to oil and gas production facilities that produce, upgrade, or store petroleum liquids and/or natural gas prior to custody transfer. This regulation contains both Major Source and Area Source requirements.

Major Source Requirements: The Major Source requirements of this regulation also apply to Storage Vessels.

Per the definitions in §63.761, the Major Source determination is based on glycol dehydration unit HAPs emissions and Storage Tanks emissions from each wellsite, independent of any other wellsites in the vicinity. No wellsite is equipped with a glycol dehydrator. Additionally, the Storage Tanks should have negligible emissions since each tank is to be equipped with a closed vent system, as discussed later. Therefore, this area is classified as an Area Source, and the Major Source requirements do not apply.

Area Source Requirements: There are no Area Source requirements in this regulation for Storage Tanks.

Title V

These units are subject to this regulation. However, as mentioned earlier, vapors from these tanks are captured and sent to the flare. Therefore, compliance with the flare requirements is sufficient.

Applicable Requirements

The following requirements shall apply:

1. Each storage vessel constructed, reconstructed, §60.5395 or modified after August 23, 2011, is subject to the requirements of 40 CFR 60 Subpart OOOO. Storage vessels with uncontrolled emissions of 6 Ton/yr of VOC, or greater, shall be equipped with a cover and/or a closed vent system routed to an approved control device, such as a flare in order to reduce VOC emissions by 95% or more.
2. Each storage vessel shall be equipped with a closed vent system that routes stock tank vapors to either the produced gas line, the fuel gas line, or the flare. Rule 335-3-14-.04 [Anti-PSD]

Expected Emissions

Since the storage tanks are to be equipped with a closed vent system, all stock tank vapors are captured and routed to the flare, the processing plant, or the fuel gas system. Therefore, the expected emission from these sources have been accounted for as discussed in the Flares section below..

Monitoring Approach

Periodic Monitoring

Periodic monitoring would consist of conducting required inspections and submitting required reports for the closed vent system according to the methods and procedures specified in §60.5416. [§60.5410, §60.5411, and §60.5415]

Compliance Assurance Monitoring [CAM]

For a unit to be subject to Compliance Assurance Monitoring (CAM), that unit must have a permit limit, a control device, and the potential to emit (PTE), pre-control, greater than 100 Ton/yr of any criteria pollutant or 10 Ton/yr of one Hazardous Air Pollutant (HAP) or 25 Ton/yr of all HAPs.

This regulation is not applicable since none of these units has the potential to emit greater than 100 Ton/yr.

(56) Wellsite Emergency Flares

Each wellsite is proposed to have an emergency flare. Even though this flare is called an emergency flare, potential emission calculations were performed assuming continuous flaring. Each flare may be used to burn excess stock tank vapors, excess fuel gas, and/or the produced wellstream in the event of a plant shutdown.

Regulatory Applicability:

This section will summarize the regulatory applicability for these units.

Prevention of Significant Deterioration [PSD]

This facility is a 250-Ton source for the purposes of PSD. Sklar has requested a facility-wide emissions limit of 245 Ton/yr for all criteria pollutants. Since the flares are the primary source of emissions, the flares will be limited to 245 Ton/yr for all flares. This limit will be met by monitoring the properties of, and the amount of, gas being flared.

ADEM Administrative Code Rule 335-3-5-.03(1-2)

This rule applies to sulfur emissions from petroleum production. Hydrogen Sulfide may not be emitted in a greater quantity than 0.10 grain per standard cubic foot (scf), or 160 ppmv, unless it is properly burned to maintain a ground concentration of less than 20 ppb beyond property limits, as averaged over a 30 minute period. Produced gas is not expected to exceed 160 ppmv. This regulation would be applicable to each well with this content or higher. Sklar has requested that this regulation be included in the permit in the event that the sulfur content is higher than expected. Combusting produced gas and stock tank vapors in the flare or transporting this gas to a treatment plant should minimize H₂S emissions.

40 CFR 60 Subpart OOOO [NSPS OOOO]

This rule was promulgated by EPA on April 17, 2012, and contains SO₂ and VOC requirements for natural gas production wells and natural gas processing plants constructed, reconstructed, or modified after August 23, 2011. The emergency well flares may be used to comply with this regulation.

Title V

Each flare is subject to this regulation.

Applicable Requirements

Each of the flares should meet the following requirements:

1. Each unit at this site is subject to all Title V source requirements. *Rule 335-3-16*
2. The total emissions from all sources at this facility shall not exceed 245 Ton/yr on NO_x, CO, VOC, and SO₂, as demonstrated by compliance with the following indicators for the emergency well flares: *Rule 335-3-14-.04 (Anti-PSD)*
 - (a) Average gas properties shall be maintained at:

- (1) Heat content ≤ 1600 BTU/Scf
 - (2) H₂S mole percent ≤ 1000 ppmv
 - (3) Molecular Weight ≤ 28 lb/lb-mole
- (b) Total gas volume flared for all flares, as indicated by the gas production rate, shall be maintained at less than, or equal to, 2 MMScf/Day AND 750 MMScf/365-Day Period.
3. Each process gas stream containing more than 0.10 of a grain of hydrogen sulfide per Scf shall not be emitted into the atmosphere unless it is properly burned to maintain the ground level concentrations of hydrogen sulfide to less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period. *Rule 335-3-5-.03(2)*
4. No person shall cause or permit the Sulfur Oxide emissions from any facility designed to dispose of or process natural gas or refinery gas containing more than 10 grains of Hydrogen Sulfide per standard cubic foot to exceed 245 Ton/yr. *Rule 335-3-5-.03(3)*
5. Each flare shall meet the requirements specified below: *Rule 335-3-4-.01(1)*
 - (a) Except for one 6-minute period during any 60-minute period, the flare shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.
 - (b) At no time shall the flare discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.
6. Each flare used to comply with 40 CFR 60 Subpart OOOO shall meet the design and operation specifications of §60.18. *§60.5412(a)(3), §60.5413(a)(1), & §60.5415(e)(1)*

Expected Emissions

The NO_x, CO, VOC, and SO₂ emissions were taken from the Sklar Area No. 3 2011 Title V emissions estimates. The H₂S emissions were based on engineering judgment derived from modeling of larger sources.

Expected emissions:

CO (Ton/yr)	24.89
VOC (Ton/yr)	23.57
NO _x (Ton/yr)	4.97
H ₂ S (ppbv, offsite)	< 1
SO ₂ (Ton/yr)	0.008

Table 7: Expected Total Flare Emissions

Monitoring Approach

Periodic Monitoring

This section outlines the applicable periodic monitoring:

Offsite Concentration

The requirement to maintain an off-site hydrogen sulfide concentration below a specific amount constitutes a facility wide emission cap and such limits are not considered to be an emission limitation that would trigger the applicability of Compliance Assurance Monitoring. Thus, periodic monitoring is applicable and shall consist of maintaining a spark or pilot light at the flare tip. It should be noted that this is essentially the same requirement as that specified in NSPS OOOO.

NO_x, CO, SO₂, & VOC [Non-NSPS OOOO]

Since the flares are the primary emission point for each wellsite, demonstrating compliance with the facility-wide limits based solely on the flares is justified. Periodic monitoring for the facility-wide limits for NO_x, CO, VOC, and SO₂ is applicable, and will have two parts. First, a semi-annual gas sample will be taken from each well stream, or a common stream, if appropriate, and analyzed for heat content, sulfur content as H₂S, and overall molecular weight. Second, Sklar will be required to minimize total flowrates of gas to the flares. For the purposes of this monitoring plan, if the well is not connected to a pipeline, all gas produced will be assumed to have been flared.

NSPS OOOO—VOC & Opacity

Flares used to comply with NSPS OOOO VOC standards are required to be equipped and operated with a heat sensor that continuously records the continuous ignition of the pilot flame.

Opacity

Periodic monitoring for the opacity standard will be required during flaring events as described in the following tables.

Compliance Assurance Monitoring [CAM]

The requirement to burn sulfur-laden gas in the flare is considered to be a work practice and not an emission limitation. Per 40 CFR 64.5(b) a facility should submit a CAM plan with its renewal application for each unit not classified as a large Pollutant Specific Emission Unit (PSEU). A large PSEU is defined as any unit with potential criteria pollutant emissions of at least 100 Ton/yr following a control device. A small PSEU is defined as any unit with potential criteria pollutant emissions less than 100 Ton/yr following a control device. Since the potential emissions from each flare are less than 100 Ton/yr, each flare is considered a small PSEU, and CAM does not apply at this time. However, Sklar should address CAM applicability in the first renewal application.

Monitoring approach:		Each Emergency Flare	
<i>Periodic Monitoring</i>		<i>Periodic Monitoring</i>	
I. Indicator		Average well gas properties for each well flare	Total well gas flared
A. Measurement approach	Well gas BTU content, H ₂ S content, and molecular weight shall be determined semi-annually, or at a frequency determined by the Department.	Well gas production volume for each wellsite shall be monitored with a system capable of measuring and recording the flow rate and/or the parameters utilized for flow rate calculation or estimated utilizing material balances, computer simulations, special testing, etc.	Well gas production volume for each wellsite shall be monitored with a system capable of measuring and recording the flow rate and/or the parameters utilized for flow rate calculation or estimated utilizing material balances, computer simulations, special testing, etc.
II. Indicator range		Average well gas properties shall be ≤: Heat content of 1600 BTU/Scf, Sulfur content of 1000 ppmv H₂S, & Molecular weight of 28 lb Gas/lb-mole Gas	The total well gas flared volume shall not exceed 2 MMScf/Day AND 750 MMScf/rolling 365-day period
	The gas property set points may be changed upon receipt of Department approval.	The maximum total well gas flared volume limits may be changed upon receipt of Department approval.	
	A deviation is defined as when the periodic gas analysis results in one, or more, of the measured gas properties exceeding the allowed values.	A deviation is defined as when the maximum total well gas flared volume exceeds the allowed Daily volume and/or the 365-Day rolling total.	
	A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.	A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.	
A QIP threshold	Not applicable	Not applicable	
III. Performance criteria			
A. Data representativeness	Well gas properties measured shall be representative of the well gas stream fed to each well flare.	Well gas production volume monitors shall be located immediately upstream of each well flare and pipeline entrance.	
	Provided multiple streams share a common flare and pipeline entrance, the gas analysis may be performed on the gas at this entrance.	Provided multiple production streams share a common flare and pipeline entrance, the well gas production monitor may be placed at this entrance.	

Monitoring approach:	Each Emergency Flare <i>Periodic Monitoring</i>	<i>Periodic Monitoring</i>
I. Indicator	Average well gas properties for each well flare	Total well gas flared
B. Verification of operational status	The well gas properties shall be averaged throughout the area.	Not applicable
C. QA/QC practices & criteria	Not applicable	The well gas production volume monitor shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent.
D. Monitoring frequency	Well gas properties shall be analyzed once each 6-months, unless otherwise approved by the Department using methods and procedures laid out in proviso 2 of the <i>Compliance & Performance Test Methods & Procedures</i> section.	If the well production volume monitor fails its calibration tests, the well gas production volume monitor shall be taken out of service until repairs and/or replacements are made and a new calibration test is undertaken and passed.
Data collection procedure	Record: Each Occurrence: Well gas: a) BTU content, b) H ₂ S content, & c) Molecular Weight determination Area gas: a) BTU content, b) H ₂ S content, & c) Molecular Weight determination	Record: Daily Site gas flared volume (in MMscf/Day) Area gas flared volume (in MMscf/Day) Annual gas flared volume [in MMscf/365-Days]
Averaging period	Date and results of each inspection and corrective actions taken. After each sample	Record: Each Occurrence: Date and results of each inspection and corrective actions taken.

Each Emergency Flare

Periodic Monitoring

Monitoring approach:

I. Indicator

- A. Measurement approach

Operate flare with a flame present at all times when a process gas stream may be sent to it.

The flare tip shall be equipped with a continuously burning pilot light that is monitored with either a thermocouple or an equivalent device or by visual observation.

II. Indicator range

Presence of a flame at flare tip

A deviation is defined as when there was no flame present at the flare tip when a process gas stream was vented to it.

A deviation triggers an immediate inspection and corrective actions and reporting within 48 hours or two work days.

- A QIP threshold

Not Applicable

III. Performance criteria

- A. Data representativeness

The flame monitor shall be located at the flare tip and focused on the area where gas exits the flare tip.

Visual observations shall be made from the location that provides the best view of the flare tip and/or flare pilot lights or flare igniter.

- B. Verification of operational status

Not applicable

- C. QA/QC practices & criteria

The flame monitor shall be maintained and calibrated in accordance with the manufacturer's specifications, other written procedures that provide adequate assurance that the device is properly maintained and calibrated accurately, or at least annually whichever is more frequent..

Repairs and/or replacements shall be made immediately when non-functioning or damaged parts are found.

- D. Monitoring frequency

Pilot flame shall be monitored either continuously with a thermocouple or daily with visual inspections if operating staff is on site.

Record time, date and duration of each incident of when no flame was present at the flare tip when a process gas stream was sent to it.

Record time, date and results of each visual observation.

Record time, date and results of each calibration.

Record time, date and results of each inspection and corrective actions taken.

- Averaging period

Instantaneous

NSPS 0000 Emergency Flares - Opacity

Periodic Monitoring—NSPS 0000

Monitoring approach:

I. Indicator

A. Measurement approach

Opacity

Provided the flare is being utilized to burn a gas stream other than the pilot light fuel gas stream, a daily visual emission observation on the flare shall be undertaken.

Duration of each observation shall be:

>= 15 minutes

and

<= 120 minutes

Each observation shall be conducted in accordance with the methods and procedures laid out in proviso 1 of the *Compliance & Performance Test Methods & Procedures* section.

II. Indicator range

The accumulated time of opacity observance shall not exceed 5 minutes.

A deviation is defined as anytime the accumulated time exceeds 5 minutes during any observation while utilizing Method 22.

A deviation triggers continued visible emissions observations at a frequency suitable to defining the duration of the visible emission deviation event.

One observation shall be undertaken to establish the end of the visible emission deviation event.

A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.

III. Performance criteria

A. Monitoring frequency

Each flaring event, or as set by the Department

Data collection
procedure

Record: Each visible emissions observation

Each 15 second observation reading

Record: Each occurrence

Time, date and results of corrective actions taken

Averaging period

Instantaneous

Non-NSPS 0000 Emergency Flares - Opacity

Monitoring approach:	Periodic Monitoring—Non-NSPS 0000
I. Indicator	Opacity
A. Measurement approach	Provided the flare is being utilized to burn a gas stream other than the pilot light fuel gas stream, a daily visual emission observation on the flare shall be undertaken.
	Duration of each observation shall be \geq 15 minutes and \leq 60 minutes
	Each observation shall be conducted in accordance with the methods and procedures laid out in proviso 1 of the <i>Compliance & Performance Test Methods & Procedures</i> section.
II. Indicator range	(1) No more than one 6-min. average opacity reading shall exceed 20%; OR, (2) No 6-min. average opacity reading shall exceed 40%; OR, (3) The accumulated time of observed visible emissions shall not exceed 12 minutes.
	A deviation is defined as anytime the observed 6-minute average opacity exceeds 20% for the 2nd time, or 40% for the 1st time, when utilizing Method 9.
	A deviation is defined as anytime the accumulated time in which visible emissions were observed exceeds 12 minutes per observation when utilizing Method 22.
	A deviation triggers continued visible emissions observations at a frequency suitable to defining the duration of the visible emission deviation event. One observation shall be undertaken to establish the end of the visible emission deviation event.
	A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.
III. Performance criteria	
A. Monitoring frequency	Daily
Data collection procedure	Record: Daily
	Each 15 second observation reading
	Record: Each occurrence – Time, date and results of corrective actions taken
Averaging period	Six minutes

Appendix A: Potential Emissions Calculations

NOTE: These Calculations are being included for the sake of completeness and to show the total site potential emissions.

Part I: Gas Analysis Summary

The following table summarizes the component gas analyses for the wells covered by this permit. Some wells have not yet had a gas analysis performed; this is mostly because the well has just been drilled or put into service. Nevertheless, Sklar should perform a gas analysis as specified in the permit for these wells, and maintain a copy of these analyses onsite. It should be remembered that the emissions are based on an average BTU content of 1600 BTU/Scf, and average H₂S content of 1000 ppmv, and a molecular weight of 28 lb/lbmol.

Well No.	Gas Component [Mole %]--based on latest analyses											Heat Content [BTU/Scf]
	N ₂	CO ₂	H ₂ S	CH ₄	C ₂ H ₆	C ₃ H ₈	i-C ₄ H ₁₀	n-C ₄ H ₁₀	i-C ₅ H ₁₂	n-C ₅ H ₁₂	C ₆ H ₁₄ +	
Logan 5-7	No gas produced--Liquids only											
Boothe-Casey 29-6	6.373	0.309	0.00001	61.649	14.235	9.082	2.048	3.513	0.894	0.897	1.000	1417.7
Thomasson 29-10	5.683	0.285	0.00020	62.971	13.583	8.199	1.927	3.577	1.097	1.178	1.674	1448.3
Ralls 30-8	Not operated in 2011											
Mary Mack 31-2	4.108	0.272	0.00010	51.721	14.383	11.090	3.300	6.862	2.550	2.848	2.866	1769.2
Hamiter 32-2	4.997	0.318	0.00030	61.296	15.447	9.388	2.095	3.646	0.925	0.930	0.960	1450.2
CCL&T 12-33-2	5.402	0.371	0.00820	63.226	14.733	8.833	1.898	3.224	0.788	0.775	0.742	1399.200
CCL&T 12-33-6	No Data--Began Drilling Operations 5/2012											
CCL&T 12-33-10	No Data--Began Drilling Operations 6/2012											
CCL&T 12-33-12	No Data--Began Drilling Operations 6/2012											
Jones 34-4	No Data--Began Operations 5/2012											
Graddy 34-8	5.241	0.311	0.00008	62.158	14.801	9.146	2.049	3.563	0.911	0.906	0.914	1433.000
Graddy 34-10	No Data--Just drilled											
CCL&T 34-14	No Data--Began Operations 6/2012											
CCL&T 35-5	No Data--Began Operations 6/2012											
CCL&T 35-8	5.965	0.240	0.00010	62.710	14.412	8.826	1.920	3.329	0.855	0.853	0.890	1405.7
CCL&T 35-10	4.324	0.367	0.00010	54.807	15.741	12.207	3.184	5.742	1.428	1.396	0.804	1598.6
CCL&T 35-11	No Data--Began Drilling Operations 4/2012											
Average:	5.262	0.309	0.00114	60.067	14.667	9.596	2.303	4.182	1.181	1.223	1.231	1490.2

Part II: Emergency Flare Emissions Summary

The averages in the previous table were used to calculate the flare emissions. The potential emissions calculated below are for one well and are based on the assumption that the average Gas Heat Content, Gas H₂S Content, and Gas VOC Mole percent, along with a total area-wide gas flare rate provide a reasonable approximation of the flare emissions across the area. 40 CFR 98 Subpart W equations W-19, W-20, W-21, and W-40 and the gas analyses were used to determine greenhouse gas emissions.

		Well (Potential)
FLOWRATE (Scf/Hr/Well)	=	1529
HEAT CONTENT (Btu/Scf)	=	1552
H ₂ S CONTENT (H ₂ S mol %)	=	0.0001
RATED HEAT CAPACITY (MMBtu/Hr)	=	2.37
VOC CONTENT (VOC mol %) ¹	=	22.22
VOC MW (Lb/Lb-Mole)	=	12.21
CH ₄ (mol%)	=	56.78
CH ₄ MW (Lb/Lb-Mole)	=	16.043
CO ₂ (mol %)	=	0.32
CO ₂ MW (Lb/Lb-Mole)	=	44.010
AP-42 Emission Factors Table 13.5-1 of the Industrial Flares Section		
NO _x		CO
0.068 Lb/MMBtu		0.37 Lb/MMBtu

40 CFR Part 98 Subpart C Greenhouse Gas Emission Factors for Natural Gas		
Natural Gas Greenhouse Gas EF (kg/MMBtu)		
CO ₂	N ₂ O	CH ₄
-	0.0001	-
(GWP=1)	(GWP=310)	(GWP=21)

¹ See Gas Analysis for mol% and molecular (MW) of each compound

MISCELLANEOUS CALCULATIONS:

Rated Heat Capacity (MMBtu/Hr) = Flowrate (Scf/Hr) * Heat Content (Btu/Scf) * (MMBtu/10⁶ Btu)

VOC (Lb/Lb-mole)¹ = Σ(Mole% of Each Compound) * (1%/100) * MW of Each Compound

SO₂ Conversion Factor 1.689 Lb SO₂/MScf of Gas
= (1,000 Scf/MScf) * (1%/100) * (1Lb-Mole/378.9 Scf) * (64 Lb SO₂/Lb-Mole)

40 CFR 98 Subpart W Equations:

E_{a, CH₄} (un-combusted) = V_a * (1-η) * X_{CH₄} (W-19)

N₂O = (1x 10⁻³) x Fuel x HHV x EF (W-40)

E_{a, CO₂} (un-combusted) = V_a * X_{CO₂} (W-20)

E_{a, CO₂} (combusted) = η * V_a Σ Y_j * R_j (W-21)

where, CH₄ and CO₂ are annual emissions in cubic feet; N₂O are annual emissions in metric tons

Flare Emission Calculations [for (1) Flare; Multiply by (56) to get total emissions]

SO₂	1.689 Lb SO ₂ MScf	1.5 Hr	0.00114 Mol%	8,760 Hr Year	1 Ton 2,000 Lb	=	0.01 Tons Year
NO_x	0.068 lb MMBtu	2.28 MMBtu Hr	8,760 Hr Year	1 Ton 2,000 Lb		=	0.68 Tons Year
CO	0.37 lb MMBtu	2.28 MMBtu Hr	8,760 Hr Year	1 Ton 2,000 Lb		=	3.69 Tons Year
VOC²	1.529 Scf Hr	1 Lb-Mole 378.9 Scf	10.80 Lb VOC Lb-Mole	8,760 Hr Year	1 Ton 2,000 Lb	=	3.82 Tons Year
CO₂^{2,3} Combusted	0.98 Yr	13,392,857 Scf Yr	1.63845 1 Lb-Mole 378.9 Scf	44.01 Lb CO ₂ Lb-mole	1 Metric Ton 2205 lb	=	1132.79 Metric Tons Year
CO₂ Uncombusted		13,392,857 Scf Yr	0.3091 100 1 Lb-Mole 378.9 Scf	44.01 Lb CO ₂ Lb-mole	1 Metric Ton 2,205 Lb	=	2.18 Metric Tons Year
N₂O⁴	Ton kg	0.001490238 scf	1,529 Scf Hr	0.0001 kg MMBtu	8,760 Hr Year	=	0.00 Metric Tons Year
CH₄ Uncombusted		13,392,857 Scf Yr	0.02 100 60.0673 1 Lb-Mole 378.9 Scf	16 Lb CH ₄ Lb-mole	1 Metric Ton 2,205 Lb	=	3.08 Metric Tons Year
Mass Sum		1,134.97 Tons Year	0.0020 Tons Year	3.08 Tons Year		=	1138.05 Metric Tons Year
CO₂^e	1,134.97 Metric Tons/yr 1,134.97 CO ₂	X 1	0.0020 Metric Tons/yr 0.62 N ₂ O	X 310	3.08 Metric Tons/yr 64.71 CH ₄	X 21	1200.30 Metric Tons Year

Part III: Heater Treater Emissions Summary

The following data was provided in the permit application for each heater. Greenhouse gas emission factors used for natural gas were obtained from 40 CFR 98 Subpart C Table C-2. The global warming potentials (GWP) are given below.

DATA:				
FLOWRATE = HEAT CONTENT = H ₂ S CONTENT = HEATER TREATER RATED HEAT INPUT = FUEL TYPE =			Well (Potential)	
			0.644 MScf/Hr	
			1552 Btu/Scf	
			0.007 Mol %	
			0.5 MMBtu/Hr	
			PRODUCED NATURAL GAS	
<u>AP-42 Emission Factors Section 1.4 for Natural Gas</u>				
<u>Combustion</u>				
<u>(Lb/MMScf)</u>				
<u>PM</u> 7.6	<u>NO_x</u> 100	<u>CO</u> 84	<u>VOC</u> 5.5	
AP-42 EF based on a Heat Content of 1,020 Btu/Scf for Natural Gas				
<u>40 CFR Part 98 Subpart C Greenhouse Gas Emission Factors for Natural Gas</u>				
Natural Gas Greenhouse Gas EF (kg/MMBtu)				
<u>CO₂</u> 53.02 (GWP=1)	<u>N₂O</u> 0.0001 (GWP=310)		<u>CH₄</u> 0.001 (GWP=21)	

MISCELLANEOUS CALCULATIONS:

Flowrate (MScf/hr) = Heat Input (Btu/Hr) * (1/Heat Content (Btu/Scf))*(1 Mscf/10³Scf)

Heater Treater Emission Calculations [for (1) Heater Treater; Multiply by (56) to get the total emissions]

PM	7.6 Lb MMScf	1,490 Btu/Scf 1,020 Btu/Scf	1 MMBtu Hr	Scf 1,490 Btu	8,760 Hr Year	1 Ton 2,000 Lb	=	0.03 Tons Year
SO₂	1.689 Lb SO ₂ MScf	0.67 MScf Hr	0.00114 Mol% Hr	8,760 Hr Year	1 Ton 2,000 Lb		=	0.01 Tons Year
NO_x	100 Lb MMScf	1,490 Btu/Scf 1,020 Btu/Scf	1 MMBtu Hr	Scf 1,490 Btu	8,760 Hr Year	1 Ton 2,000 Lb	=	0.43 Tons Year
CO	84 Lb MMScf	1,490 Btu/Scf 1,020 Btu/Scf	1 MMBtu Hr	Scf 1,490 Btu	8,760 Hr Year	1 Ton 2,000 Lb	=	0.36 Tons Year
VOC	5.5 Lb MMScf	1,490 Btu/Scf 1,020 Btu/Scf	1 MMBtu Hr	Scf 1,490 Btu	8,760 Hr Year	1 Ton 2,000 Lb	=	0.02 Tons Year
CO₂	1 MMBtu Hr	53.02 kg MMBtu	2.20462 Lb kg	8,760 Hr Year	1 Metric Ton 2,205 Lb		=	464.38 Metric Tons Year
N₂O	1 MMBtu Hr	0.0001 kg MMBtu	2.20462 Lb kg	8,760 Hr Year	1 Metric Ton 2,205 Lb		=	0.00 Metric Tons Year
CH₄	1 MMBtu Hr	0.001 kg MMBtu	2.20462 Lb kg	8,760 Hr Year	1 Metric Ton 2,205 Lb		=	0.01 Metric Tons Year
GHG Mass	464.38 Metric Tons Year	+	0.0009 Metric Tons Year	+	0.0088 Metric Tons Year		=	464.38 Metric Tons Year
CO₂e	464.38 Metric Tons/yr X 1 464.38 CO ₂	+	0.0009 Metric Tons/yr X 0.27 N ₂ O	+	0.0088 Metric Tons/yr X 0.18 CH ₄		=	464.83 Metric Tons Year

Part IV: Storage Tank Emissions Summary

The following table summarizes the emissions that would be expected from the tanks if the tanks were allowed to vent to atmosphere. However, since the tanks are equipped with a closed vent system, these emissions have been accounted for in the flare calculations.

Tank No.	Contents	Volume [GAL]	VOC Emissions [Ton/yr]	Emissions Basis
1	Salt water	20,000	3.212	Tanks 4.0 Program for 500 BBL Tank
2	Crude Oil	20,000	3.212	Tanks 4.0 Program for 500 BBL Tank
3	Crude Oil	20,000	3.212	Tanks 4.0 Program for 500 BBL Tank
4	Crude Oil	20,000	3.212	Tanks 4.0 Program for 500 BBL Tank
5	Crude Oil	20,000	3.212	Tanks 4.0 Program for 500 BBL Tank
Total/Well site:			16.06	Ton/yr/Site
Total [All Sites]:			899.36	Ton/yr

Part V: Total Emissions Summary

The following table summarizes the emissions for the heater treaters and flares throughout the Area:

Facility-Wide Potential Emissions Castleberry Area No. 3 Oil & Gas Production Wells								
Emissions Sources	(Tons/yr)						(Metric Tons/yr)	
	PM	SO ₂	NO _x	CO	VOC	HAPs	CO ₂ e	GHG Mass
(56) Heater Treaters	1.83	0.32	24.05	20.20	1.32	Negligible	26030.51	26005.55
(56) Emergency Flares	-	0.72	38.00	206.77	213.70	Negligible	67216.61	63731.07
Total Emissions:	1.83	1.04	62.05	226.97	215.02	Negligible	93247.13	89736.62

This table is reproduced above.

Appendix B: Draft Permit



MAJOR SOURCE OPERATING PERMIT

Permitee: **Sklar Exploration, LLC**

Facility Name: **Castleberry Oil & Gas Field, Area No. 3**

Facility No.: 502-0090

Location: Sec. 5, 6, 7, & 8, T3N, R13E, Escambia County, AL
Sec. 19, 20, 29, 30, 31, 32, & 33, T4N, R13E,
Conecuh County, AL
Sec. 33, 34, 35, & 36, T4N, R12E, Conecuh
County, AL

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, as amended, Ala. Code 1975, §§22-28-1 to 22-28-23 (2006 Rplc. Vol. and 2007 Cum. Supp.) (the "AAPCA") and the Alabama Environmental Management Act, as amended, Ala. Code 1975, §§22-22A-1 to 22-22A-15, (2006 Rplc. Vol. and 2007 Cum. Supp.) and rules and regulations adopted thereunder, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

*Pursuant to the **Clean Air Act of 1990**, all conditions of this permit are federally enforceable by EPA, the Alabama Department of Environmental Management, and citizens in general. Those provisions which are not required under the **Clean Air Act of 1990** are considered to be state permit provisions and are not federally enforceable by EPA and citizens in general. Those provisions are contained in separate sections of this permit.*

Issuance Date: **DRAFT**

Expiration Date: **DRAFT**

GENERAL PERMIT PROVISOS 1

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General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>1. <u>Transfer</u> This permit is not transferable, whether by operation of law or otherwise, either from one location to another, from one piece of equipment to another, or from one person to another, except as provided in Rule 335-3-16-.13(1)(a)5.</p>	Rule 335-3-16-.02(6)
<p>2. <u>Renewals</u> An application for permit renewal shall be submitted at least six (6) months, but not more than eighteen (18) months, before the date of expiration of this permit. The source for which this permit is issued shall lose its right to operate upon the expiration of this permit unless a timely and complete renewal application has been submitted within the time constraints listed in the previous paragraph.</p>	Rule 335-3-16-.12(2)
<p>3. <u>Severability Clause</u> The provisions of this permit are declared to be severable and if any section, paragraph, subparagraph, subdivision, clause, or phrase of this permit shall be adjudged to be invalid or unconstitutional by any court of competent jurisdiction, the judgment shall not affect, impair, or invalidate the remainder of this permit, but shall be confined in its operation to the section, paragraph, subparagraph, subdivision, clause, or phrase of this permit that shall be directly involved in the controversy in which such judgment shall have been rendered.</p>	Rule 335-3-16-.05(e)
<p>4. <u>Compliance</u> (a) The permittee shall comply with all conditions of ADEM Admin. Code 335-3. Noncompliance with this permit will constitute a violation of the Clean Air Act of 1990 and ADEM Admin. Code 335-3 and may result in an enforcement action; including but not limited to, permit termination, revocation and reissuance, or modification; or denial of a permit renewal application by the permittee. (b) The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.</p>	Rule 335-3-16-.05(f)
	Rule 335-3-16-.05(g)

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>5. <u>Termination for Cause</u></p> <p>This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance will not stay any permit condition.</p> <p>6. <u>Property Rights</u></p> <p>The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.</p> <p>7. <u>Submission of Information</u></p> <p>The permittee must submit to the Department, within 30 days or for such other reasonable time as the Department may set, any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. Upon receiving a specific request, the permittee shall also furnish to the Department copies of records required to be kept by this permit.</p> <p>8. <u>Economic Incentives, Marketable Permits, and Emissions Trading</u></p> <p>No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.</p> <p>9. <u>Certification of Truth, Accuracy, and Completeness:</u></p> <p>Any application form, report, test data, monitoring data, or compliance certification submitted pursuant to this permit shall contain certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.</p>	<p>Rule 335-3-16-.05(h)</p> <p>Rule 335-3-16-.05(i)</p> <p>Rule 335-3-16-.05(j)</p> <p>Rule 335-3-16-.05(k)</p> <p>Rule 335-3-16-.07(a)</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>10. <u>Inspection and Entry</u></p> <p>Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized representatives of the Alabama Department of Environmental Management and EPA to conduct the following:</p> <p>(a) Enter upon the permittee's premises where a source is located or emissions-related activity is conducted, or where records must be kept pursuant to the conditions of this permit;</p> <p>(b) Review and/or copy, at reasonable times, any records that must be kept pursuant to the conditions of this permit;</p> <p>(c) Inspect, at reasonable times, this facility's equipment (including monitoring equipment and air pollution control equipment), practices, or operations regulated or required pursuant to this permit;</p> <p>(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or other applicable requirements.</p>	<p>Rule 335-3-16-.07(b)</p>
<p>11. <u>Compliance Provisions</u></p> <p>(a) The permittee shall continue to comply with the applicable requirements with which the company has certified that it is already in compliance.</p> <p>(b) The permittee shall comply in a timely manner with applicable requirements that become effective during the term of this permit.</p>	<p>Rule 335-3-16-.07(c)</p>
<p>12. <u>Compliance Certification</u></p> <p>A compliance certification shall be submitted within 60 days of the end of the reporting period of each year.</p> <p>(a) The compliance certification shall include the following:</p> <p>(1) The identification of each term or condition of this permit that is the basis of the certification;</p>	<p>Rule 335-3-16-.07(e)</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>(2) The compliance status;</p> <p>(3) The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);</p> <p>(4) Whether compliance has been continuous or intermittent;</p> <p>(5) Such other facts as the Department may require to determine the compliance status of the source;</p> <p>(b) The compliance certification shall be submitted to:</p> <p style="text-align: center;">Alabama Department of Environmental Management Air Division P.O. Box 301463 Montgomery, AL 36130-1463 and to:</p> <p style="text-align: center;">Air and EPCRA Enforcement Branch EPA Region IV 61 Forsyth Street, SW Atlanta, GA 30303</p>	
<p>13. <u>Reopening for Cause</u></p> <p>Under any of the following circumstances, this permit will be reopened prior to the expiration of the permit:</p> <p>(a) Additional applicable requirements under the Clean Air Act of 1990 become applicable to the permittee with a remaining permit term of three (3) or more years. Such a reopening shall be completed not later than eighteen (18) months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which this permit is due to expire.</p> <p>(b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into this permit.</p>	<p>Rule 335-3-16-.13(5)</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>(c) The Department or EPA determines that this permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.</p> <p>(d) The Administrator or the Department determines that this permit must be revised or revoked to assure compliance with the applicable requirements.</p>	
<p>14. <u>Additional Rules and Regulations</u></p> <p>This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.</p>	
<p>15. <u>Equipment Maintenance or Breakdown</u></p> <p>(a) In the case of shutdown of air pollution control equipment (which operates pursuant to any permit issued by the Director) for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Director at least twenty-four (24) hours prior to the planned shutdown, unless such shutdown is accompanied by the shutdown of the source which such equipment is intended to control. Such prior notice shall include, but is not limited to the following:</p> <ol style="list-style-type: none"> (1) Identification of the specific facility to be taken out of service as well as its location and permit number; (2) The expected length of time that the air pollution control equipment will be out of service; (3) The nature and quantity of emissions of air contaminants likely to occur during the shutdown period; (4) Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period; (5) The reasons that it would be impossible or impractical to shut down the source operation during the maintenance period. 	<p>§22-28-16(d), Code of Alabama 1975, as amended</p> <p>Rule 335-3-1-.07(1) & (2)</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>(b) In the event that there is a breakdown of equipment or upset of process in such a manner as to cause, or is expected to cause, increased emissions of air contaminants which are above an applicable standard, the person responsible for such equipment shall notify the Director within 24 hours or the next working day and provide a statement giving all pertinent facts, including the estimated duration of the breakdown. The Director shall be notified when the breakdown has been corrected.</p>	
<p>16. <u>Operation of Capture and Control Devices</u></p> <p>All air pollution control devices and capture systems for which this permit is issued shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.</p>	<p>§22-28-16(d), Code of Alabama 1975, as amended</p>
<p>17. <u>Obnoxious Odors</u></p> <p>This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.</p>	<p>Rule 335-3-1-.08</p>
<p>18. <u>Fugitive Dust</u></p> <p>(a) Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.</p> <p>(b) Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:</p> <p>(1) By the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;</p>	<p>Rule 335-3-4-.02</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>(2) By reducing the speed of vehicular traffic to a point below that at which dust emissions are created;</p> <p>(3) By paving;</p> <p>(4) By the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;</p> <p>Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.</p>	
<p>19. <u>Additions and Revisions</u></p> <p>Any modifications to this source shall comply with the modification procedures in Rules 335-3-16-.13 or 335-3-16-.14.</p>	<p>Rule 335-3-16-.13 & Rule 335-3-16-.13.14</p>
<p>20. <u>Recordkeeping Requirements</u></p> <p>(a) Records of required monitoring information of the source shall include the following:</p> <p>(1) The date, place, and time of all sampling or measurements;</p> <p>(2) The date analyses were performed;</p> <p>(3) The company or entity that performed the analyses;</p> <p>(4) The analytical techniques or methods used;</p> <p>(5) The results of all analyses; and</p> <p>(6) The operating conditions that existed at the time of sampling or measurement.</p>	<p>Rule 335-3-16-.05(c)2.</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>(b) Retention of records of all required monitoring data and support information of the source for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation and copies of all reports required by the permit</p>	
<p>21. <u>Reporting Requirements</u></p> <p>(a) Reports to the Department of any required monitoring shall be submitted at least every 6 months. All instances of deviations from permit requirements must be clearly identified in said reports. All required reports must be certified by a responsible official consistent with Rule 335-3-16-.04(9).</p> <p>(b) Deviations from permit requirements shall be reported within 48 hours or 2 working days of such deviations, including those attributable to upset conditions as defined in the permit. The report will include the probable cause of said deviations, and any corrective actions or preventive measures that were taken.</p>	<p>Rule 335-3-16-.05(c)(3).</p>
<p>22. <u>Emission Testing Requirements</u></p> <p>Each point of emission which requires testing will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.</p> <p>The Air Division must be notified in writing at least 10 days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.</p> <p>To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:</p>	<p>Rule 335-3-1-.05(3) & Rule 335-3-1-.04(1)</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>(1) The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.</p> <p>(2) A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedures require probe cleaning).</p> <p>(3) A description of the process(es) to be tested including the feed rate, any operating parameters used to control or influence the operations, and the rated capacity.</p> <p>(4) A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.</p>	<p>Rule 335-3-1-.04</p>
<p>A pretest meeting may be held at the request of the source owner or the Air Division. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.</p> <p>All test reports must be submitted to the Air Division within 30 days of the actual completion of the test unless an extension of time is specifically approved by the Air Division.</p>	<p>Rule 335-3-1-.04</p>
<p>23. <u>Payment of Emission Fees</u></p> <p>Annual emission fees shall be remitted each year according to the fee schedule in ADEM Admin. Code R. 335-1-7-.04.</p>	<p>Rule 335-1-7-.04</p>
<p>24. <u>Other Reporting and Testing Requirements</u></p> <p>Submission of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require emission testing at any time.</p>	<p>Rule 335-3-1-.04(1)</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>25. <u>Title VI Requirements (Refrigerants)</u></p> <p>Any facility having appliances or refrigeration equipment, including air conditioning equipment, which use Class I or Class II ozone-depleting substances as listed in 40 CFR Part 82, Subpart A, Appendices A and B, shall service, repair, and maintain such equipment according to the work practices, personnel certification requirements, and certified recycling and recovery equipment specified in 40 CFR Part 82, Subpart F.</p> <p>No person shall knowingly vent or otherwise release any Class I or Class II substance into the environment during the repair, servicing, maintenance, or disposal of any device except as provided in 40 CFR Part 82, Subpart F.</p> <p>The responsible official shall comply with all reporting and recordkeeping requirements of 40 CFR 82.166. Reports shall be submitted to the US EPA and the Department as required.</p> <p>26. <u>Chemical Accidental Prevention Provisions</u></p> <p>If a chemical listed in Table 1 of 40 CFR Part 68.130 is present in a process in quantities greater than the threshold quantity listed in Table 1, then:</p> <p>(a) The owner or operator shall comply with the provisions in 40 CFR Part 68.</p> <p>(b) The owner or operator shall submit one of the following:</p> <p>(1) A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR Part 68 § 68.10(a) or,</p> <p>(2) A certification statement that the source is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan.</p>	<p>40 CFR Part 82</p> <p>40 CFR Part 68</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>27. <u>Display of Permit</u></p> <p>This permit shall be kept under file or on display at all times at the site where the facility for which the permit is issued is located and will be made readily available for inspection by any or all persons who may request to see it.</p>	<p>Rule 335-3-14-.01(1)(d)</p>
<p>28. <u>Circumvention</u></p> <p>No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes any emission of air contaminant which would otherwise violate the Division 3 rules and regulations.</p>	<p>Rule 335-3-1-.10</p>
<p>29. <u>Visible Emissions</u></p> <p>Unless otherwise specified in the Unit Specific provisos of this permit, any source of particulate emissions shall not discharge more than one 6-minute average opacity greater than 20% in any 60-minute period. At no time shall any source discharge a 6-minute average opacity of particulate emissions greater than 40%. Opacity will be determined by 40 CFR Part 60, Appendix A, Method 9, unless otherwise specified in the Unit Specific provisos of this permit.</p>	<p>Rule 335-3-4-.01(1)</p>
<p>30. <u>Fuel-Burning Equipment</u></p> <p>(a) Unless otherwise specified in the Unit Specific provisos of this permit, no fuel-burning equipment may discharge particulate emissions in excess of the emissions specified in Part 335-3-4-.03.</p> <p>(b) Unless otherwise specified in the Unit Specific provisos of this permit, no fuel-burning equipment may discharge sulfur dioxide emissions in excess of the emissions specified in Part 335-3-5-.01.</p>	<p>Rule 335-3-4-.03</p> <p>Rule 335-3-5-.01</p>
<p>31. <u>Process Industries – General</u></p> <p>Unless otherwise specified in the Unit Specific provisos of this permit, no process may discharge particulate emissions in excess of the emissions specified in Part 335-3-4-.04.</p>	<p>Rule 335-3-4-.04</p>

General Permit Provisos

Federally Enforceable Provisos	Regulations
<p>32. <u>Averaging Time for Emission Limits</u></p> <p>Unless otherwise specified in the permit, the averaging time for the emission limits listed in this permit shall be the nominal time required by the specific test method.</p> <p>33. <u>Permit Shield</u></p> <p>A permit shield exists under this operating permit in accordance with ADEM Admin. Code 335-3-16-.10 in that compliance with the conditions of this permit shall be deemed in compliance with any applicable requirements as of the date of permit issuance. The permit shield is based on the accuracy of the information supplied in the application for this permit. Under this shield, it has been determined that requirements listed as non-applicable in the application are not applicable to this source.</p>	<p>Rule 335-3-1-.05</p> <p>Rule 335-3-16-.10</p>

Summary Page for Production Well Sources & Emergency Flares

Permitted Operating Schedule: **24 Hours/Day x 365 Days/Year = 8760 Hours/Year**

Emission limitations:

Emission Point #	Description	Pollutant	Emission Limit	Regulation
See Below	<u>Facility-Wide Emissions:</u>	SO ₂	< = 245 Ton/yr*	Rule 335-3-14-.04 (Anti-PSD)
See Below	Pre-8/23/2011 Sources	NO _x	< = 245 Ton/yr*	Rule 335-3-14-.04 (Anti-PSD)
See Below	Post-8/23/2011 Sources	VOC	< = 245 Ton/yr*	Rule 335-3-14-.04 (Anti-PSD)
See Below	Heater Treaters	CO	< = 245 Ton/yr*	Rule 335-3-14-.04 (Anti-PSD)
See Below	Storage Tanks	H ₂ S	20 ppbv of H ₂ S off site	Rule 335-3-5-.03(2)

* As indicated by compliance with the following:

Average Gas Properties:

Heat Content

< = 1600 BTU/Scf

H₂S Content

< = 1000 ppmv

Molecular Weight

< = 28 lb/lb-mole

Flare Feedrate:

< = 2 MMScf

Day

< = 750 MMScf

365-Days

Pre-August 23, 2011, Wellsites w/Flares, Wellheads, Pneumatic Controllers, & Storage Tanks

Affected Wells [Unless reconstructed AND/OR modified]:

T3N, R13E: Sec. 5,6,7, & 8:

0507A, & Logan 5-7, &
0704A CCL&T 7-4

T4N, R12E: Sec. 33,34,35, & 36:

3508A, CCL&T 35-8, &
& 3510A CCL&T 35-10

T4N, R13E: Sec. 19,20,29,30,32, & 33:

2910A Thomasson 29-10,
3102A, & Mary Mack 31-2, &
3203A Hamiter 32-3

(7) Emergency Well Flares:

Each Flare

Opacity

< 20%

Rule 335-3-4-.01(1)

Emission Point #	Description	Pollutant	Emission Limit	Regulation
	(7) Closed Vent Systems:			
	Each Closed Vent System	VOC	None	
	(7) Wellheads:			
	Each Hydraulically Re-Fractured gas well	VOC	Work Practices per §60.5375	§60.5365(h)(1) & (2)
	Storage Tanks/ Wellsite:			
	(4) 20,000 gallon tanks:			
	(1) Water Tanks			
	(2) Crude Oil Tanks			
	(1) Power Oil Pump Tank			
	w/VOC ≥ 6 Ton/yr	VOC	None	§60.5365(h)(3)
	w/VOC < 6 Ton/yr	VOC	None	§60.5365(h)(3)

Post-August 23, 2011, Wellsites w/Flares, Wellheads, Pneumatic Controllers, & Storage Tanks

Affected Wells [Reconstructed AND/OR modified wells/equipment also subject to these requirements]:

<u>T3N, R13E: Sec. 5,6,7,& 8:</u>		<u>T4N, R12E: Sec. 33,34,35, & 36:</u>	
05NWA,	5-NW,	12-3302A,	CCL&T 12-33-2,
05SEA,	5-SE,	12-3306A,	CCL&T 12-33-6,
05SWA,	5-SW,	12-3310A,	CCL&T 12-33-10,
06NEA,	6-NEA	12-3312A,	CCL&T 12-33-12,
06NWA,	6-NW,	3404A,	Jones 34-4,
06SEA,	6-SE,	3408A,	Graddy 34-8,
06SWA,	6-SW,	3410A,	Graddy 34-10,
07NEA,	7-NEA	3414A,	CCL&T 34-14,
07SEA,	7-SE,	3505A,	CCL&T 35-5,
07SWA,	7-SW,	3511A,	CCL&T 35-11,
08NEA,	8-NEA	36NEA,	36-NE,
08NWA,	8-NW,	36NWA,	36-NW,
08SEA, &	8-SE, &	36SEA, &	36-SE, &
08SWA	8-SW	36SWA	36-SW

Emission Point #	Description	Pollutant	Emission Limit	Regulation
<u>T4N, R13E: Sec. 19,20,29,30,32, & 33:</u>				
19NEA,	19-NEA,			
19NWA,	19-NW,			
19SEA,	19-SE,			
19SWA,	19-SW,			
20NEA,	20-NE,			
20NWA,	20-NW,			
20SEA,	20-SE,			
20SWA,	20-SW,			
29NEA,	29-NEA,			
2906A,	Boothe-Casey 29-6,			
29SWA,	29-SW,			
3008A,	Ralls 30-8,			
32NEA,	32-NE,			
32SEA,	32-SE,			
13-33NEA,	13-33-NE,			
13-33NWA,	13-33-NW,			
13-33SEA, &	13-33-SE, &			
13-33SWA	13-33-SW			

(49) Emergency Well Flares + Modified/Reconstructed Flares:

Each Flare:

Used to comply w/ NSPS OOOO	Opacity	Smokeless	§60.18
OR			
All other Flares	Opacity	< 20%	Rule 335-3-4-.01(1)

(49) Closed Vent Systems + Modified/Reconstructed Systems:

Each Closed Vent System:

Used to comply w/ NSPS OOOO	VOC	Work Practices from §60.5416	§60.5411
OR			
All other Closed Vent Systems	VOC	None	

(49) Wellheads + Re-fractured Wells:

Each Hydraulically Fractured gas well	VOC	Work Practices per §60.5375	§60.5365(h)(4)
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Each Storage Tanks/Site:

(4) 20,000 gallon tanks:

- (1) Water Tanks
- (2) Crude Oil Tanks
- (1) Power Oil Pump Tank

w/VOC ≥ 6 Ton/yr	VOC	Work Practices per §60.5395	§60.5365(e)
w/VOC < 6 Ton/yr	VOC	None	

Emission Point #	Description	Pollutant	Emission Limit	Regulation
(56) 0.5 MMBTU/hr Heater Treaters	Each unit	Opacity	< 20%**	Rule 335-3-4-.01(1)
		NO _x	None	
		CO	None	
		VOC	None	
		SO ₂	4.0 lb/MMBTU**	Rule 335-3-5-.01(1)
		PM	0.5 lb/MMBTU**	Rule 335-3-4-.03

** As indicated by burning only sweetened natural gas as fuel [T & I Sources]

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<i>Applicability</i>	
<p>1. The flares share an enforceable limit in order to prevent the facility from being subject to the provisions of <i>ADEM Admin. Code R. 335-3-14-.04</i>, "Air Permits Authorizing Construction in Clean Air Areas" [Prevention of Significant Deterioration (PSD)]. The following definitions will be used in this permit:</p> <p style="margin-left: 40px;">(a) Area = All wellsites permitted herein</p> <p style="margin-left: 40px;">(b) Volume Flared = Volume Produced, when gas is not sent to a pipeline for processing or sale.</p>	Rule 335-14-.04 [Anti-PSD]
<p>2. Each source listed on the summary page is subject to Rule 335-3-16.</p>	Rule 335-3-16-.03
<p>3. Each flare that burns gas that contains more than 0.10 grains of hydrogen (H_2S) per standard cubic foot (Scf) shall be subject to <i>ADEM Admin. Code R. 335-3-5-.03</i>.</p>	Rule 335-3-5-.03(1)
<p>4. The requirements of 40 CFR 60 Subpart OOOO apply as follows:</p> <p style="margin-left: 40px;">(a) Applicable definitions are listed in §60.5430.</p> <p style="margin-left: 40px;">(b) Table 3 of the regulation lists the applicable portions of the General Provisions.</p> <p style="margin-left: 40px;">(c) Since Wells 5-7, 7-4, 29-10, 31-2, 32-2, 35-8, and 35-10 were completed prior to August 23, 2011, the following equipment at these wells are existing sources exempt from this regulation:</p> <p style="margin-left: 80px;">(1) Each wellhead, unless the wellhead is hydraulically re-fractured according to the procedures in §60.5375.</p> <p style="margin-left: 80px;">(2) Each storage tank, unless the tank is modified OR reconstructed.</p>	<p>40 CFR 60.5430</p> <p>40 CFR 60.5425</p> <p>40 CFR 60.5365(h)(1) & (2)</p> <p>40 CFR 60.5365(e) & (h)(3)</p>

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>(d) Since the other wells listed on the summary page were completed after to August 23, 2011, the following equipment at these wells, and reconstructed/modified sources, are subject to this regulation:</p> <p>(1) Each wellhead that is hydraulically fractured OR re-fractured according to the procedures in §60.5375.</p> <p>(2) Each storage tank</p> <p>(e) Each affected source shall be in compliance by the date specified in the regulation.</p>	<p>40 CFR 60.5365(a) & (h)(4)</p> <p>40 CFR 60.5365(e)</p> <p>40 CFR 60.5370</p>
<i>Emission Standards</i>	
<p>1. The following requirements shall apply to each source subject to 40 CFR 60 Subpart OOOO:</p> <p>(a) Each hydraulically fractured or re-fractured gas well completion operation shall comply with the methods and procedures specified in §60.5375.</p> <p>(b) Each storage tank shall comply with the applicable methods and procedures specified in §60.5395.</p> <p>(c) Each pneumatic controller shall comply with the applicable methods and procedures specified in §60.5390.</p> <p>(d) Each flare utilized with a cover and/or closed vent system to reduce the storage tank VOC emissions by 95%, or more, shall meet the following:</p> <p>(1) The design and operational parameters shall meet the standards specified in §60.18.</p> <p>(2) Visible emissions shall not exceed 5 minutes during any consecutive 120-minute period.</p>	<p>40 CFR 60.5365(a) & (h)(4)</p> <p>40 CFR 60.5365(e)</p> <p>40 CFR 60.5365(d)</p> <p>40 CFR 60.5412(a)(3), 40 CFR 60.5413(a)(1), & 40 CFR 60.5415(e)(1)</p> <p>40 CFR 60.5412(a)(3), 40 CFR 60.5413(a)(1), & 40 CFR 60.5415(e)(1)</p>

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>(3) A heat sensing monitoring device and continuous pilot flame recorder shall be installed and operated at all times.</p>	<p>40 CFR 60.5395(c)(1) & (2), 40 CFR 60.5410(e)(7), 40 CFR 60.5412(b)(2), 40 CFR 60.5415(e)(1) & (2), & 40 CFR 60.5417(d)(1)(iii)</p>
<p>2. At no time shall the facility-wide NO_x, CO, VOC, and/or SO₂ emissions exceed 245 Tons/Consecutive 12-month period. Compliance with this requirement shall be demonstrated by the following methods:</p>	
<p>(a) The following requirements apply to the Flares:</p>	<p>Rule 335-3-14-.04 [Anti-PSD]</p>
<p>(1) Each Flare shall be equipped, and operated, with:</p>	
<p>(i) An Air Assist system</p>	
<p>(ii) A spark igniter or continuous pilot light</p>	
<p>(2) The total gas volume burned in all Flares shall not exceed the following, as demonstrated by either continuous measurement OR engineering calculations.</p>	
<p>(i) 750 MMScf per any consecutive 365-day period</p>	
<p style="text-align: center;">AND</p>	
<p>(ii) 2 MMScf/Day</p>	
<p>(3) If a flare is NOT used to comply with 40 CFR 60 Subpart OOOO, then the following requirements shall apply for Visible Emissions:</p>	
<p>(i) Except for one 6-minute period during any 60-consecutive minute period, each flare shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.</p>	

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>(ii) At no time shall each flare discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.</p>	
<p>(b) Each storage vessel shall be equipped with a closed vent system, routed to either the flare, fuel gas system, or to the plant pipeline immediately upon start-up.</p>	<p><u>All Tanks:</u> Rule 335-3-14-.04 [Anti-PSD]</p> <p><u>NSPS OOOO Tanks:</u> 40 CFR 60.5395</p>
<p>(c) Each Heater Treater shall meet the following, as indicated by burning only sweetened natural gas OR purchased propane OR other fuel permitted by the Department:</p>	
<p>(1) Particulate emissions shall not exceed 0.5 lb/MMBTU.</p>	<p>Rule 335-3-14-.04 [Anti-PSD] & Rule 335-3-4-.03</p>
<p>(2) SO₂ emissions shall not exceed 4.0 lb/MMBTU.</p>	<p>Rule 335-3-14-.04 [Anti-PSD] & Rule 335-3-5-.01(1)</p>
<p>(d) The area-wide average well gas properties shall be at, or below the following, unless otherwise allowed by the Department:</p>	<p>Rule 335-3-14-.04 [Anti-PSD]</p>
<p>(1) Heat Content: 1600 BTU/Scf</p>	
<p>(2) H₂S Content: 1000 ppmv</p>	
<p>(3) Gas Molecular Weight: 28 lb/lb-mole</p>	
<p>(e) Each process gas stream containing more than 0.10 of a grain of hydrogen sulfide per Scf shall not be emitted into the atmosphere unless it is properly burned to maintain the ground level concentrations of hydrogen sulfide to less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period.</p>	<p>Rule 335-3-5-.03(2)</p>

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>3. Upon completion of a generic well, the facility shall submit a request for a Temporary Authorization to Operate including information. This notification will also satisfy the notification requirement from §60.5420(a)(2) for hydraulically fractured/re-fractured gas well completion operations.</p> <p>(a) Well name</p> <p>(b) Well UTM Coordinates</p> <p>(c) Driving directions to the site OR a map showing the roads</p>	<p><u>Generic Wells:</u> Rule 335-3-14-.01(f)</p> <p><u>NSPS OOOO Wells:</u> 40 CFR 60.5375(c) & (e), 40 CFR 60.5410(a)(1), & 40 CFR 60.5420(a)(2)(ii)</p>
<p><i>Compliance and Performance Test Methods and Procedures</i></p>	
<p>1. Visible emissions observations shall be conducted using either Method 9 OR Method 22 of Appendix A of 40 CFR Part 60.</p>	<p>Rule 335-3-16-.05(c)(1)(i) & Rule 335-3-1-.05</p>
<p>2. Each well gas sample shall be analyzed using the following methods and procedures:</p> <p>(a) For H₂S Content, while utilizing the Tutwiler procedures in 40 CFR §60.648 or the chromatographic analysis procedures in ASTM E-260 or the stain tube procedures in GPA 2377-86 or those provided by the stain tube manufacture. [SG Stream (H₂S Mole %)]</p> <p>(b) For VOC mole percent, Molecular Weight, and BTU Content, while utilizing the chromatographic analysis procedures in 40 CFR Part 60 Appendix A, Method 18, Method 25A, ASTM Method D1826-77, or equivalent methods and procedures. [SG Stream (VOC Mole%)] [SG Stream (Mole Wt)] [SG Stream (BTU/Scf)]</p> <p>(c) The analysis methods used, monitoring locations, sampling frequencies, components tested for, etc., may be altered upon receipt of Department approval.</p>	<p>Rule 335-3-16-.05(c)(1)(i) & Rule 335-3-1-.05</p>

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>3. The uncontrolled VOC emissions from each storage tank shall be determined using either TANKS 4.0, or another industry-accepted calculation method.</p> <p>4. Each process gas stream that has to be vented to the atmosphere shall be captured and sent to a flare so that it can be burned.</p> <p style="padding-left: 40px;">(a) Compliance shall be demonstrated by conducting a process flow design evaluation of the production facility in conjunction with a visual inspection of the facility.</p> <p style="padding-left: 40px;">(b) Except when vessels and equipment are being depressured and/or emptied and the reduced pressure will not allow flow of the gas to a control device, the venting to the atmosphere of any process gas stream that is subject to this proviso for a duration in excess of 15 continuous minutes shall be deemed a exceedance of requirements specified in proviso 1(e) of the <i>emission standards</i> section of this subpart.</p>	<p>40 CFR 60.5395</p> <p>Rule 335-3-16-.05(c)(1)(i) & Rule 335-3-1-.05</p>
<i>Emission Monitoring</i>	
<p>1. Monitoring meeting the requirements specified in Appendix A of this permit shall be utilized for the all flares.</p> <p>2. Compliance with visible emissions standard shall be demonstrated by either:</p> <p style="padding-left: 40px;">(a) A daily visual inspection of the flare shall be undertaken.</p> <p style="padding-left: 40px;">(b) If during this inspection, visible emissions are observed, then a visible emissions observation as outlined in Appendix B shall be undertaken for the appropriate type flare.</p>	<p>Rule 335-3-16-.05(c)(1), Rule 335-3-1-.04, & Rule 335-3-16-.05(c)(1)(ii)</p> <p>Rule 335-3-16-.05(c)(1), Rule 335-3-1-.04, & Rule 335-3-16-.05(c)(1)(ii)</p>

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
3. Within the specified period of time and frequency, the uncontrolled VOC emissions shall be calculated from each storage tank constructed after August 23, 2011, using the procedures specified in proviso 3 of the <i>Compliance & Performance Test Methods & Procedures</i> section.	40 CFR 60.5395
4. Each closed vent system and/or cover installed in order to comply with 40 CFR 60 Subpart OOOO shall be inspected and monitored at the frequency and using the methods and procedures specified in §60.5416.	40 CFR 60.5395, 40 CFR 60.5410, 40 CFR 60.5411, 40 CFR 60.5412, & 40 CFR 60.5415
5. The fuel gas volume burned in the heater treaters shall be determined using either continuous monitors OR engineering estimates.	Rule 335-3-16-.05(c)(1), Rule 335-3-1-.04, & Rule 335-3-16-.05(c)(1)(ii)
<i>Record Keeping and Reporting Requirements</i>	
1. For the purpose of demonstrating compliance with provisos 1 through 4 of the <i>emission standards</i> section of this subpart, a monthly record of the information specified in provisos 1(a) through (e) of this section of this subpart shall be maintained and made available for inspection for each flare for a period of five (5) years.	
(a) For each wellsite:	Rule 335-3-16-.05(c)(2) & Rule 335-3-1-.04
(1) Site Daily Gas Flared [MMScf/Day]	
(2) Site Daily Gas to Pipeline [MMScf/Day]	
(3) A copy of the most recent gas analysis containing the following information:	
(i) Site Heat Content [BTU/Scf]	
(ii) Site Sulfur Content [mole % H ₂ S]	
(iii) Site Gas Molecular Weight [lb/lb-mole]	
(b) For the facility:	Rule 335-3-16-.05(c)(2) & Rule 335-3-1-.04

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>(1) Area Daily Gas Flared [MMScf/Day] = Σ Site Daily Gas Flared [MMScf/Day]</p> <p>(2) Area Annual Gas Flared [MMScf/365-Day] = Area Daily Gas Flared [MMScf/Day] + Σ Area Daily Gas Volume Flared [MMScf/Day] for previous 364 days</p> <p>(3) An average of the most recent gas analyses for each site containing the following information:</p> <p style="padding-left: 40px;">(i) Average Area Heat Content [BTU/Scf]</p> <p style="padding-left: 40px;">(ii) Average Area Sulfur Content [mole % H₂S]</p> <p style="padding-left: 40px;">(iii) Average Area Gas Molecular Weight [lb/lb-mole]</p> <p>(c) For each heater treater:</p> <p style="padding-left: 40px;">(1) A copy of the fuel usage for each unit</p> <p style="padding-left: 40px;">(2) A copy of the fuel gas analysis, unless this is the same as the well gas analysis.</p> <p>(d) A copy of all records required by 40 CFR 60 Subpart OOOO, as specified in §60.5420.</p> <p>(e) The date, starting time, duration, and results of all flare visible emissions observations or flare inspections as described in proviso 2 of the <i>emission monitoring</i> section of this subpart of this permit.</p> <p>(f) The date, starting time, and duration of each deviation or exceedance, along with the emissions, cause and corrective actions taken.</p> <p>(g) The frequency of the recordkeeping period may be altered upon receipt of Departmental approval.</p>	<p>Rule 335-3-16-.05(c)(2) & Rule 335-3-1-.04</p> <p>40 CFR 60.5420</p> <p>Rule 335-3-16-.05(c)(2) & Rule 335-3-1-.04</p> <p>Rule 335-3-16-.05(c)(2) & Rule 335-3-1-.04</p> <p>Rule 335-3-16-.05(c)(2) & Rule 335-3-1-.04</p>

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>2. Periodic Monitoring Reports meeting the requirements specified in proviso 2(a) through (c) of this section of this subpart shall be submitted to the Department.</p> <p>(a) Each report shall identify each incidence of deviation from a permit term or condition including those that occur during startups, shutdowns, and malfunctions. A deviation shall mean any instance in which emission limits, emission standards, and/or work practices were not complied with, as indicated by observations, data collection, and monitoring specified in this permit. Some examples of deviations are:</p> <ol style="list-style-type: none"> (1) There was a failure to maintain the presence of a flame or igniter spark at the flare tip when a process gas stream could have been sent to it. (2) There was a failure to take immediate corrective actions when a deviation was determined to have occurred. (3) One, or more, process gas streams were vented to atmosphere for more than 15 consecutive minutes in duration. (4) Process gas stream H_2S, and/or Btu content and/or the molecular weight exceeded the setpoints in proviso 2(a) of the <i>emission standards</i> section of this subpart of this permit. (5) The flared gas flowrate exceeded the setpoint in proviso 2(b) of the <i>emission standards</i> section of this subpart of this permit (6) The 30-minute average offsite hydrogen sulfide concentration exceeded 20 ppbv, as determined by air quality modeling study. 	<p>Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(i)</p>

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<p>(7) For non-NSPS OOOO flares, the opacity exceeded 20% for more than one 6-minute averaging period during any consecutive 60-minute period.</p> <p>(8) For non-NSPS OOOO Flares, the opacity exceeded 40% during any 6-minute averaging period.</p> <p>(9) The requirements specified in 40 CFR 60 Subpart OOOO were not complied with, were not complied with properly, and/or were not complied with at the appropriate frequency.</p> <p>(10) Visible emissions observations were not conducted for the required 12 minute duration when utilizing Method 9 OR Method 22.</p> <p>(11) Well gas stream H₂S, and/or Btu content was not determined at the appropriate frequency, or with the correct methods.</p> <p>(12) Required monitoring was not conducted according to the specified monitoring plans.</p> <p>(13) Records were not kept appropriately.</p> <p>(14) Reports were not submitted appropriately.</p> <p>(b) For each deviation event, the following information shall be submitted.</p> <p>(1) Emission source description</p> <p>(2) Permit requirement</p> <p>(3) Date</p> <p>(4) Starting time of pollutant or parameter</p> <p>(5) Duration</p>	

Provisos for Production Well Sources & Emergency Flares

Federally Enforceable Provisos	Regulations
<ul style="list-style-type: none"> (6) Actual quantity of pollutant or parameter (7) Cause (8) Actions taken to return to normal operating conditions (9) Total operating hours of the affected source during the reporting period (10) Total hours of deviation events during the reporting period (11) Total hours of deviation events that occurred during start ups, shut downs, and malfunctions during the reporting period (c) If no deviation event occurred during the reporting period, a statement that indicates there were no deviations from the permit requirements shall be included in the report. (d) Each report shall cover a calendar semi-annual period and shall be submitted within thirty days of the end reporting period. (e) The report content and format in proviso 2(a) through (c) of this section may be modified upon receipt of Departmental approval. 	
<p>3. All reports specified in §60.5420 shall be submitted to the Department and EPA Region 4 at the frequency specified in the regulation.</p>	<p>40 CFR 60.5420</p>
<p>4. Each deviation from the requirements, including those that occur during start ups, shut downs, and malfunctions, shall be reported to the Department in a manner that complies with proviso 15(b) and 21(b) of the <i>General Provisos</i> subpart of this permit.</p>	<p>Rule 335-3-16-.05(c)(3)(ii)</p>

Appendix A: Monitoring for Emergency Flares

Each Emergency Flare

Monitoring approach:	<i>Periodic Monitoring</i>	<i>Periodic Monitoring</i>
I. Indicator	Average well gas properties for each well flare	Total well gas flared
A. Measurement approach	<p>Well gas BTU content, H₂S content, and molecular weight shall be determined semi-annually, or at a frequency determined by the Department.</p> <p>No sample is required for a well with no gas production, as demonstrated by the continuous monitors described in the next column. Any gas production requires an immediate sample. Gas burned as flare pilot gas is not included.</p> <p>Average well gas properties shall be ≤: Heat content of 1600 BTU/Scf, Sulfur content of 1000 ppmv H₂S, & Molecular weight of 28 lb Gas/lb-mole Gas</p> <p>The gas property set points may be changed upon receipt of Department approval.</p> <p>A deviation is defined as when the periodic gas analysis results in one, or more, of the measured gas properties exceeding the allowed values.</p> <p>A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.</p> <p>Not applicable</p> <p>Well gas properties measured shall be representative of the well gas stream fed to each well flare.</p> <p>Provided multiple streams share a common flare and pipeline entrance, the gas analysis may be performed on the gas at this entrance.</p>	<p>Well gas production volume for each wellsite shall be monitored with a system capable of measuring and recording the flow rate and/or the parameters utilized for flow rate calculation or estimated utilizing material balances, computer simulations, special testing, etc.</p> <p>For the purposes of this monitoring plan, the well gas production volume shall be equated to the total well gas flared volume.</p> <p>The total well gas flared volume shall not exceed 2 MMScf/Day AND 750 MMScf/rolling 365-day period</p> <p>The maximum total well gas flared volume limits may be changed upon receipt of Department approval.</p> <p>A deviation is defined as when the maximum total well gas flared volume exceeds the allowed Daily volume and/or the 365-Day rolling total.</p> <p>A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.</p> <p>Not applicable</p> <p>Well gas production volume monitors shall be located immediately upstream of each well flare and pipeline entrance.</p> <p>Provided multiple production streams share a common flare and pipeline entrance, the well gas production monitor may be placed at this entrance.</p>
II. Indicator range		
A QIP threshold		
III. Performance criteria		
A. Data representativeness		

Monitoring approach:	Each Emergency Flare <i>Periodic Monitoring</i>	<i>Periodic Monitoring</i>
I. Indicator	Average well gas properties for each well flare	Total well gas flared
The well gas properties shall be averaged throughout the area.		
B. Verification of operational status	Not applicable	Not applicable
C. QA/QC practices & criteria	Not applicable	The well gas production volume monitor shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent.
D. Monitoring frequency	Well gas properties shall be analyzed once each 6-months, unless otherwise approved by the Department using methods and procedures laid out in proviso 2 of the <i>Compliance & Performance Test Methods & Procedures</i> section.	If the well production volume monitor fails its calibration tests, the well gas production volume monitor shall be taken out of service until repairs and/or replacements are made and a new calibration test is undertaken and passed. Well gas production volumes shall be monitored continuously. The daily well gas flared volume shall be added to the well gas flared volumes for the previous 364 days.
Data collection procedure	Record: Each Occurrence: Well gas: a) BTU content, b) H ₂ S content, & c) Molecular Weight determination Area gas: a) BTU content, b) H ₂ S content, & c) Molecular Weight determination	Record: Daily Site gas flared volume (in MMscf/Day) Area gas flared volume (in MMscf/Day) Annual gas flared volume [in MMscf/365-Days]
Averaging period	Date and results of each inspection and corrective actions taken. After each sample	Record: Each Occurrence: Date and results of each inspection and corrective actions taken. Daily

Each Emergency Flare

Periodic Monitoring

Monitoring approach:

I. Indicator

- A. Measurement approach

Operate flare with a flame present at all times when a process gas stream may be sent to it.

The flare tip shall be equipped with a continuously burning pilot light that is monitored with either a thermocouple or an equivalent device or by visual observation.

II. Indicator range

Presence of a flame at flare tip

A deviation is defined as when there was no flame present at the flare tip when a process gas stream was vented to it.

A deviation triggers an immediate inspection and corrective actions and reporting within 48 hours or two work days.

- A QIP threshold

Not Applicable

III. Performance criteria

- A. Data representativeness

The flame monitor shall be located at the flare tip and focused on the area where gas exits the flare tip.

Visual observations shall be made from the location that provides the best view of the flare tip and/or flare pilot lights or flare igniter.

- B. Verification of operational status

Not applicable

- C. QA/QC practices & criteria

The flame monitor shall be maintained and calibrated in accordance with the manufacturer's specifications, other written procedures that provide adequate assurance that the device is properly maintained and calibrated accurately, or at least annually whichever is more frequent..

Repairs and/or replacements shall be made immediately when non-functioning or damaged parts are found.

- D. Monitoring frequency

Pilot flame shall be monitored either continuously with a thermocouple or daily with visual inspections if operating staff is on site.

Record time, date and duration of each incident of when no flame was present at the flare tip when a process gas stream was sent to it.

- Data collection procedure

Record time, date and results of each visual observation.

Record time, date and results of each calibration.

Record time, date and results of each inspection and corrective actions taken.

- Averaging period

Instantaneous

Appendix B: Monitoring for Opacity for Emergency Well Flares

NSPS 0000 Emergency Flares - Opacity

Periodic Monitoring—NSPS 0000

Monitoring approach:

I. Indicator

A. Measurement approach

Opacity

Provided the flare is being utilized to burn a gas stream other than the pilot light fuel gas stream, a daily visual emission observation on the flare shall be undertaken.

Duration of each observation shall be:

>= 15 minutes

and

<= 120 minutes

Each observation shall be conducted in accordance with the methods and procedures laid out in proviso 1 of the *Compliance & Performance Test Methods & Procedures* section.

II. Indicator range

The accumulated time of opacity observance shall not exceed 5 minutes.

A deviation is defined as anytime the accumulated time exceeds 5 minutes during any observation while utilizing Method 22.

A deviation triggers continued visible emissions observations at a frequency suitable to defining the duration of the visible emission deviation event.

One observation shall be undertaken to establish the end of the visible emission deviation event.

A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.

III. Performance criteria

A. Monitoring frequency

Each flaring event, or as set by the Department

Data collection procedure

Record: Each visible emissions observation

Each 15 second observation reading

Record: Each occurrence

Time, date and results of corrective actions taken

Averaging period

Instantaneous

Non-NSPS OOOO Emergency Flares - Opacity

Periodic Monitoring—Non-NSPS OOOO

Monitoring approach:

I. Indicator

A. Measurement approach

Opacity

Provided the flare is being utilized to burn a gas stream other than the pilot light fuel gas stream, a daily visual emission observation on the flare shall be undertaken.

Duration of each observation shall be ≥ 15 minutes and ≤ 60 minutes

Each observation shall be conducted in accordance with the methods and procedures laid out in proviso 1 of the *Compliance & Performance Test Methods & Procedures* section.

II. Indicator range

(1) No more than one 6-min. average opacity reading shall exceed 20%; OR, (2) No 6-min. average opacity reading shall exceed 40%; OR, (3) The accumulated time of observed visible emissions shall not exceed 12 minutes.

A deviation is defined as anytime the observed 6-minute average opacity exceeds 20% for the 2nd time, or 40% for the 1st time, when utilizing Method 9.

A deviation is defined as anytime the accumulated time in which visible emissions were observed exceeds 12 minutes per observation when utilizing Method 22.

A deviation triggers continued visible emissions observations at a frequency suitable to defining the duration of the visible emission deviation event. One observation shall be undertaken to establish the end of the visible emission deviation event.

A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.

III. Performance criteria

A. Monitoring frequency

Daily

Data collection procedure

Record: Daily

Each 15 second observation reading

Record: Each occurrence – Time, date and results of corrective actions taken

Averaging period

Six minutes